Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Mike Abel. I am a Project Manager for PGE.

My name is Greg Batzler. I am a Senior Regulatory Consultant for PGE.

Our qualifications appear in Section VII of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to request recovery of the revenue requirement associated with the second and third phases (i.e., PGE's owned and contracted portions) of the Clearwater Wind Project (Clearwater), a qualifying renewable resource project, through PGE's Schedule 122, pursuant to Oregon Revised Statutes (ORS) 757.210 and 469A.120(3). Specifically, we request recovery of the fixed costs, operations and maintenance (O&M) costs, income taxes, property taxes, and other fees and costs associated with Clearwater, including any Schedule 125 eligible net variable power costs (NVPC) before 2025. Additionally, Schedule 122 allows for the deferral and collection of the revenue requirement prior to the tariff effective date for this proceeding.

Q. What period of time does this request cover?

A. For the purposes of setting Schedule 122 prices, PGE requests the Public Utility Commission of Oregon (OPUC or Commission) authorize tariffs to collect an annualized amount associated with Clearwater, which is based upon the calendar year of January 1, 2024 through December 31, 2024. The PGE's owned and contracted phases of Clearwater have a current estimated in-service date of December 31, 2023. As we approach the end of 2023, PGE expects to provide updates on the project status. PGE requests a tariff effective date for

Schedule 122 of June 1, 2024, and will seek to include net amounts deferred prior to the tariff update effective date on January 1, 2025, or as soon as practicable within Schedule 122.

Q. Please briefly describe Clearwater.

A. The entire Clearwater project (i.e., all four phases) is a 775 MW wind generation facility that will span Rosebud, Garfield, and Custer counties in Montana. Of the 775 MW of total expected nameplate capacity, 208 MW of the wind generation facility (referred to as "Clearwater East") will be owned by PGE and subject to a build-transfer-agreement (BTA), while an additional 103 MW (referred to as "Clearwater II") will be sold to PGE under a power purchase agreement (PPA). The remaining 464 MW from the first and fourth phases of Clearwater are neither owned nor contracted to PGE and are not a part of our request.

Q. Please summarize PGE's requested revenue requirement in this filing.

A. PGE is requesting an approximate $9.9 million decrease to incremental revenue requirement for Clearwater. This includes a full year of forecast 2024 NVPC benefits based on PGE's October power cost update within Docket No. UE 416. Using the October update filing as the starting point, the current incremental forecast of 2024 NVPC benefits for Clearwater, including production tax credits (PTCs), is approximately ($74.9 million).[1] This includes incremental Energy Community PTC benefits associated with the Inflation Reduction Act of 2022 (IRA), which were not known at the time Clearwater was bid into PGE's 2021 Request for Proposals (RFP). As we discuss further in Section IV, these incremental benefits, along with the energy and diversity benefits forecast within NVPC, represent a significant value to customers, leading to an overall price decrease due to the inclusion of Clearwater into

[1] In our testimony, any negative or credit amounts are signified as ($_____) unless otherwise stated as a decrease.

customer prices. Table 1 below summarizes PGE's 2024 revenue requirement for Clearwater. We have also included the Clearwater 2024 revenue requirement as PGE Exhibit 101.

Table 1
Revenue Requirement Summary
($000s)

Rev Req Category	**2024 Forecast**
Sales to Consumers	($9,898)
Net Variable Power Costs	(74,893)
Production O&M	3,500
A&G	289
Depreciation	16,845
Misc. Expense	(86)
Franchise Fees	(254)
Property Taxes	6,462
Other Taxes	271
Income Taxes	7,665
Operating Income*	**$30,305**
Return on Equity	9.5%

** May not sum due to rounding*

Q. Will PGE also be filing for deferred accounting for Clearwater?

A. Yes. While the revenue requirement provided here is a forecast annualized revenue requirement, we currently expect that Clearwater will be placed into service prior to the effective date of Schedule 122. Additionally, PGE will be incurring certain transmission costs prior to Clearwater's online date that are directly associated with the testing and commissioning of the facility. As such, amounts directly associated with facility testing and commissioning and any amounts incurred following Clearwater's online date but prior to the tariff effective date will be deferred for future recovery within Schedule 122.

Q. Does PGE have any other proposals associated with the request to incorporate Clearwater into customer prices?

A. Yes. While we have currently included an estimate of PTC carryforwards within our accumulated deferred income tax (ADIT) estimate, we also include a proposal for the transferability of generated PTCs associated with Clearwater generation. This proposal is discussed in Section V.

Q. Does PGE have a proposal regarding the generated renewable energy certificates (RECs) associated with Clearwater prior to 2030?

A. PGE is still determining the most prudent course of action regarding the near-term RECs generated from Clearwater. We discuss this further in Section V.

Q. What Rate of Return (ROR) is PGE using for this filing?

A. PGE is using ROR detail from our 2024 general rate case (GRC).[2] Specifically, we include a Return on Equity of 9.50% and a Cost of Debt of 4.485%, which are the result of a filed stipulation in the docket, which as of October 27, 2023, is pending Commission approval. Using these amounts results in an ROR of approximately 6.993%. Ultimately, the ROR and any other revenue-sensitive factors will align with the Commission Order for PGE's 2024 GRC.

Q. What is the overall impact of the above revenue requirement on customer prices?

A. The revenue requirement, as reflected above, represents an overall 0.3% decrease to retail revenues.

Q. How will the ($9.9 million) total Schedule 122 refund be spread?

A. The revenue requirement in this filing will be spread in accordance with Schedule 122, with costs allocated to each schedule based on an equal percentage of generation revenue.

Q. How is the remainder of your testimony organized?

A. After this introductory section, we have six sections:

- Section II: Integrated Resource Plan (IRP) and Request for Proposals (RFP) Processes;

[2] Docket No. UE 416.

- Section III: Clearwater Facility and Technology;
- Section IV: Clearwater Project Costs and Revenue Requirement;
- Section V: PTC and REC Proposals;
- Section VI: Clearwater Timeline and Milestones; and
- Section VII: Qualifications.

II. IRP and RFP Processes

A. IRP Process and Identification of Energy Need

Q. Did PGE identify a need for a renewable resource in its 2019 IRP?

A. Yes. PGE's 2019 IRP and IRP Update forecast a capacity shortfall beginning in 2025.[3] Through a robust analysis, PGE's 2019 IRP Action Plan identified a capacity need of 511 MW[4] in 2025 and provided that PGE would conduct a renewables RFP seeking up to approximately 150 MWa[5] of renewable resources and clean capacity resources that contribute to meeting PGE's capacity needs by the end of 2024.

Q. Did the Commission acknowledge PGE's 2019 IRP Renewable Action Plan?

A. Yes. The Commission acknowledged PGE's 2019 IRP Renewable Action Plan in Order No. 20-152 on May 6, 2020. Following this, PGE filed a 2019 IRP Update, which contained no changes to the Renewable Action Plan, that was acknowledged in Order No. 21-129 on May 3, 2021.

Q. Is the development of Clearwater consistent with the Commission-acknowledged 2019 IRP Renewable Action Plan?

A. Yes. When Clearwater is complete, the project will provide approximately 300 MW of emissions-free generation for PGE and our customers.[6] PGE expects that when fully online, the Clearwater project will generate 141 MWa annually, which is aligned with PGE's

[3] PGE's 2019 IRP was acknowledged, with conditions and additional directives, in Order No. 20-152 and PGE's 2019 IRP Update was acknowledged, with guidance, in Order No. 21-129.

[4] This 2025 capacity need decreased from 511 MW to 372 MW after PGE renewed a long-term hydroelectric PPA with the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS) for their share of the Pelton Round Butte (PRB) output (Docket No. UM 2176). The renewed PPA will be effective from 2025 through 2040. Additionally, after incorporating the March 2022 load forecast, the 2025 capacity need slightly increased to 388 MW (for further detail see "PGE's Final Shortlist and IE's Closing Report" dated May 5, 2022, in Docket No. UM 2166).

[5] We note that Commission Order No. 22-315 acknowledged PGE's final shortlist and included a condition that the most "reasonable course of action" would be to target an acquisition level of 250 MWa.

[6] After accounting for line losses from the facility to the point of interconnection.

Renewable Action Plan need of approximately 150 MWa[7] and below the subsequent RFP short-list approval's reasonable target level of 250 MWa.[8] We discuss the development of Clearwater in Section VI.

Q. Will Clearwater RECs be used for RPS compliance purposes?

A. Yes. As stated in PGE's 2019 IRP Renewable Action Plan, procurement of an RPS-eligible resource contributes to meeting near-term energy and capacity needs as well as long-term renewable resource requirements.[9]

B. Request for Proposals Process and Selection of Resource

Q. When did PGE issue an RFP for RPS-compliant resources?

A. We began our RFP process in April 2021 (Docket No. UM 2166). After a robust process with OPUC Staff and intervenors, and Commission approval,[10] PGE issued its final RFP to market in December 2021.

Q. Was an Independent Evaluator (IE) selected to oversee the RFP?

A. Yes. In accordance with Competitive Bidding Rules,[11] Bates White was selected to serve as the IE for the RFP. The IE reported directly to the Commission and its work was directed by OPUC Staff. The IE participated in the entire RFP process from design, through bid receipt and analysis, to the selection of the shortlist, continuing through final negotiations with all selected counterparties. As part of this engagement, the IE monitored bidder contact, including the answers to bidder questions; provided input with respect to bidder disqualifications; reviewed all price and non-price scores and models for PGE's shortlist process; independently

---

[7] Acknowledged through Commission Order No. 20-152 (Docket No. LC 73).
[8] The increase to 250 MWa was a result of increased carbon energy targets established through the passage of House Bill (HB) 2021, which occurred during the pendency of PGE's 2021 RFP proceeding.
[9] PGE's 2019 IRP (Docket No. LC 73), page 33.
[10] Commission Order No. 21-460.
[11] OAR 860-089-0200.

scored all bids; submitted closing reports to the Commission after PGE identified the final shortlist; and reviewed and verified PGE's price update following the acknowledgement of PGE's final shortlist.

Q. Did PGE propose a Scoring and Modeling Methodology consistent with OAR 860-089-0250?

A. Yes. Prior to the submission of PGE's draft RFP and in conjunction with filing to request approval of an IE, PGE attached a proposed scoring and modeling methodology, consistent with OAR 860-089-0250(a). Ultimately, PGE's scoring and modeling methodology for the 2021 RFP was adopted, with certain Staff recommended conditions, through Commission Order No. 21-320.

Q. Did the RFP design have any other changes following the adoption of a scoring and modeling methodology?

A. Yes. Subsequent to the adoption of a scoring and modeling methodology and as part of the approval of PGE's RFP, the Commission ordered additional modifications to the RFP design, which PGE incorporated into the final RFP issued to market.

Q. How did PGE evaluate the renewable energy resource bids?

A. PGE evaluated the renewable energy resource bids based on a combination of price and non-price points, with 81.2% of available bid points to bids based on the price and performance considerations reflected in the price score and 18.8% of the available bid points to bids based on non-price factors that could not be readily converted into minimum bidder requirements. PGE also followed specific scoring criteria and methodology for renewable bids as specified in the Commission-approved final 2021 RFP. Additionally, consistent with the 2019 IRP and IRP Update process, PGE incorporated our Interim Transmission Solution and a costcontainment screen ("value to cost evaluation") to accommodate the renewable and non-emitting requirements of HB 2021. While the value to cost evaluation was used for analysis, it was not mandatory for bids to pass this evaluation to be considered for the initial shortlist.

Q. Please elaborate on PGE's Interim Transmission Solution.

A. In the 2019 IRP proceeding (Docket No. LC 73), PGE filed a transmission addendum (i.e., Interim Transmission Solution) that proposed a pilot approach for allowing a wider range of transmission arrangements to be applied to non-dispatchable resources (i.e., renewable energy resources).[12] In the past, PGE had required 100% long-term firm service for projects delivered to PGE's service territory. The Interim Transmission Solution specifically addressed the long-term firm service limitations in the region by allowing for a mix of long-term firm and long-term conditional firm products for 80% of a facility's output and allowing short-term firm products for the remaining.

In accordance with PGE's Interim Transmission Solution, for a renewable energy resource to qualify for the 2021 RFP, a Bidder must have had an achievable plan for long-term transmission service (e.g., long-term firm, long-term conditional firm bridge, or long-term conditional firm reassessment) for 80% of the interconnection limit of the facility. Short-term firm services may be used for the remaining 20% of the facility's interconnection limit.

Q. How did PGE determine the price scores?

A. PGE prepared financial models for all submitted bids. These models calculated a lifecycle economic value for each bid. The final price score was based on the ratio of the bid's (1) total real levelized costs to (2) the real levelized benefits of expected energy value, capacity value,

[12] See Section 3 "Program Summary" from PGE's Interim Transmission Solution, available here: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAQ&FileName=lc73haq1558.pdf&DocketID=21929&numSequence=44

and flexibility value over the same term, and was consistent with analysis performed in PGE's acknowledged 2019 IRP and IRP Update and consistent with the scoring methodology adopted through Commission Order No. 21-320 and approval of PGE's RFP through Commission Order No. 21-460.

Additionally, there were price scoring impacts for bids without 100% long-term transmission per PGE's Interim Transmission Solution. Specifically, bids were only credited capacity value for the portion of a resource delivered on long-term transmission and capacity value was not assessed for the portion of a resource delivered on short-term firm. Further, for resources that planned to rely on conditional firm service, that resource's expected output was reduced by the number of hours of identified allowed curtailment.[13]

Q. How did PGE determine the non-price scores?

A. Certain project-specific risks and benefits cannot be captured or quantified by evaluating a bid's price or resource portfolio cost benefit. For these risks and benefits, PGE evaluated and assigned a non-price score that focused on various commercial and economic risks pursuant to the matrix and scoring criteria published and approved in the final RFP. Specifically, non-price scores for renewable resources were determined based on considerations of commercial performance risk, transmission plan attributes, and the level capacity ratio score (a measure of a resource's capacity contribution to MWa).

Q. How many bids were received in response to PGE's offering?

A. PGE received bids from 19 counterparties, who together offered 110 distinct proposals, including 15 Benchmark proposals. The process, designed in conformance with the

[13] PGE's 2019 IRP Addendum, Interim Transmission Solution, page 10.

Competitive Bidding Rules,[14] required the Benchmark bids to be received and evaluated prior to PGE's receipt of all other bids. Following the receipt and scoring of all offers, PGE identified an initial shortlist containing 44 bids that included diverse commercial structures and resource technologies representing 1,915 MWa of total energy generation, with 1,325 MWa of non-benchmark resources. PGE identified the initial shortlist after performing individual bid analysis and assigning both price and non-price scores.

Q. How were the final project capacity factors determined for each bid?

A. Consistent with the Competitive Bidding Rules,[15] PGE retained an independent renewable energy expert, Hendrickson Renewables (Hendrickson), to provide an independent analysis and opinion on the energy estimates for the short-listed wind and solar resources submitted to PGE. Hendrickson provided reports on each energy estimate, each of which outlined adjustments related to the gross energy estimate, the gross to net conversion process, the uncertainty evaluation, and the combination of the three. In its reports, Hendrickson proposed adjusted net capacity factors (NCF) to each of the bidders' original resource evaluations. PGE incorporated these adjusted NCFs into the price scoring model for all initial short-listed bids.

Q. How was the final shortlist developed?

A. In addition to the combination of price and non-price scores used to determine the initial shortlist, PGE requested and received best and final offers, performed additional due diligence to confirm conformance with the 2021 RFP requirements, and updated scores to identify PGE's final shortlist. Finally, PGE performed a portfolio analysis to inform the development of the final shortlist. This analysis, in addition to the price and non-price scores, allowed PGE

[14] OAR 860-089-0350.
[15] OAR 860-089-0400.

to create a final shortlist that identified the RPS qualifying resources representing the least-cost and least-risk options for our customers and the company.

Q. How many bids made the final shortlist?

A. From the initial shortlist of 44 bids, 29 were placed on PGE's final shortlist, which represented 13 unique projects. Of that total, PGE's final renewables shortlist included a total of nine renewable projects with 18 total project variations, representing enough projects to generate 434 unique MWa of renewable energy.[16]

Q. Did the IE file a final shortlist report?

A. Yes. The IE concluded in its final shortlist report filed on May 5, 2022 that the RFP process was run in accordance with the rules and that the process was reasonably competitive.[17] Specific to the benchmark bids submitted in the process, the IE undertook a multi-part review of the offers, ultimately concluding that the benchmark bids were acceptable.[18] The IE also stated portfolio modeling suggested a clear preference for bids consistent with PGE's shortlist scoring.[19] Finally, the IE confirmed the selected bids were all reasonably priced, were selected fairly in accordance with the approved RFP scoring system, and that the RFP aligned with PGE's IRP process.[20]

Q. Were there any price scoring updates after the Commission's final shortlist acknowledgement on July 14, 2022?[21]

[16] UM 2166 *Request for Acknowledgment of the Final Shortlist of Bidders in Portland General Electric Company's 2021 All-Source Request for Proposals* PGE's Final Shortlist Request for Acknowledgement, May 25, 2022. page 18.
[17] UM 2166 *Request for Acknowledgment of the Final Shortlist of Bidders in Portland General Electric Company's 2021 All-Source Request for Proposals.* Bates White Final Closing Report, May 5, 2022. page 1.
[18] *Id.* 8.
[19] *Id.* 2.
[20] *Id*. 1-2.
[21] UM 2166 *Request for Acknowledgment of the Final Shortlist of Bidders in Portland General Electric Company's 2021 All-Source Request for Proposals.* Order No. 22-315.

A. Yes. Due to unusual events, including global supply chain disruptions, significant inflation levels, and the passage of the IRA, PGE offered all final shortlisted bidders an additional opportunity to modify the price and/or COD terms of their bids. Bidders were allowed to adjust their prices higher or lower and update their COD within the limits set by the previously established RFP COD constraints. These updates were submitted by bidders on August 26, 2022, which resulted in refreshed price scoring and portfolio modeling analysis.

Q. What were the results of this update?

A. As a result of the update, there were changes in the overall bid scores. More projects scored a cost/benefit ratio above 100%, and the ranking of the top performing bids shifted, with renewable offers paired with storage becoming less economically advantageous. Significantly, Clearwater, which was already ranked as a top performing bid within PGE's final shortlist, now emerged as the highest performing bid from a cost/benefit perspective. Additionally, Clearwater, along with two other unique bid offers, were selected as the top offers in PGE's portfolio modeling.

Q. How did Clearwater's ranking compare with the other two top offers?

A. Clearwater was included in a top-performing portfolio 146 times. For comparison, the second top offer was included in a top-performing portfolio 84 times, while the third-ranked bid was included 67 times.

Q. Did the IE review PGE's refreshed price scoring and portfolio modeling analysis?

A. Yes. PGE consulted with the IE through this process and provided the IE with updated price scores and rankings for the remaining shortlisted bids.[22] After examining all the information

[22] Following shortlist acknowledgement, two additional offers were withdrawn from the process.

provided, the IE concluded that PGE had appropriately modeled and updated prices for all offers using the methods and models in the RFP.[23]

[23] Confidential PGE Exhibit 102 provides the IE letter and analysis results.

III. Clearwater Wind Project

A. Technology

Q. Please describe the Clearwater Wind Project.

A. The Clearwater Wind Project is a 776 MW wind generation facility that will span Rosebud, Garfield, and Custer counties in Montana. The project consists of the following phases:

- Clearwater I – this first phase achieved COD in November 2022 and is a 366 MW wind project not owned by or contracted with PGE. The first 81 miles of the approximately 100-mile generation tie line that will be utilized for PGE's portion of Clearwater was built as part of this phase.
- Clearwater II – this phase will consist of 37 General Electric (GE) wind turbine generators[24] with a total nameplate capacity of approximately 103 MW which will be sold to PGE under a PPA. An additional ~10 miles of the approximately 100-mile generation tie line will be constructed as part of this phase. The anticipated COD for Clearwater II is December 31, 2023.
- Clearwater East – this phase will consist of 75 GE wind turbine generators[25] with a total nameplate capacity of approximately 208 MW, which will be owned by PGE and subject to a BTA. The remaining ~10 miles of the approximately 100-mile generation tie line will be constructed in support of this phase. The anticipated COD for Clearwater East is December 31, 2023.

[24] Five 2.52 MW turbines and 32 2.82 MW turbines.
[25] 12 2.52 MW turbines and 63 2.82 MW turbines.

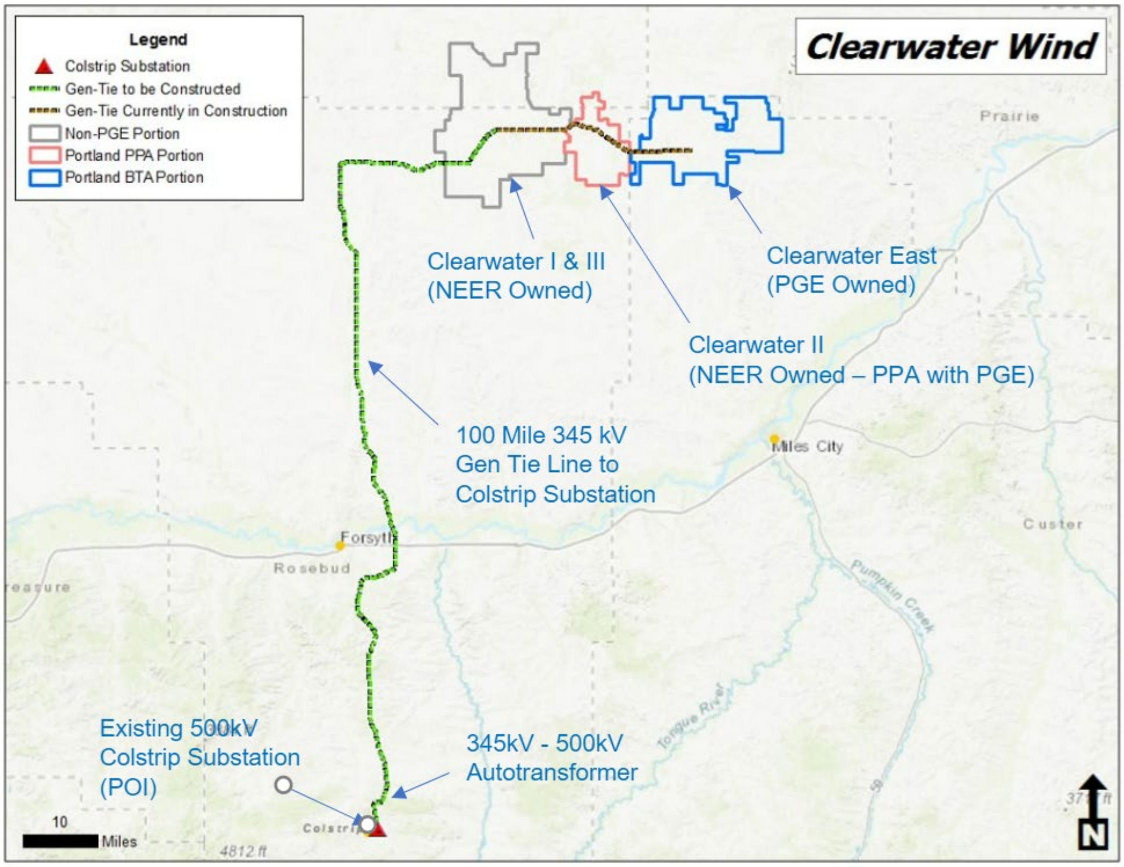
- Clearwater III – this final phase will have a total nameplate capacity of approximately 100 MW, has an anticipated COD of the end of 2024 and will not be owned by or contracted to PGE.

The 103 MW of Clearwater II that will be sold to PGE under a PPA and the 208 MW of Clearwater East that will be owned by PGE and subject to a BTA will provide a total nameplate of 311 MW[26] of emissions-free generation for PGE customers. All phases of Clearwater will connect to the existing NorthWestern Energy (NWE) Colstrip Substation 500kv via a new 100-mile generation tie line constructed and owned by Clearwater Energy Resources LLC, (Clearwater Resources) a subsidiary of NextEra Energy Resources (NEER).

PGE will own an O&M building and project substation for Clearwater East, including substation's the high voltage equipment necessary to connect the facility to the shared 100-mile generation tie line.

[26] While the total nameplate is 311 MW, available delivery to the Colstrip Substation is 300 MW.

Figure 1
Map of Clearwater Facility, Generation Tie Line, and Colstrip Substation



Q. Who is responsible for the construction and operation of Clearwater?

A. Subsidiaries of NEER will build and operate the entire facility, including PGE's owned portion. Additional key parties will include an Engineering, Procurement, and Construction (EPC) contractor hired by Clearwater Wind East LLC (Clearwater East) along with the independent engineer, Sargent and Lundy, who was mutually agreed upon by PGE and Clearwater East.

Q. Will Clearwater be in PGE's balancing authority area (BAA)?

A. Yes. However, Clearwater is physically located within the NorthWestern Energy (NWE) BAA and will connect to a generation-tie line owned by Clearwater Resources that interconnects with the Colstrip Substation, which is part of the Colstrip Transmission System

(CTS) that has a shared ownership structure between PGE and four additional parties.[27] PGE is entering into separate agreements with NWE and the Bonneville Power Administration (BPA) to enable PGE to pseudo-tie[28] Clearwater into PGE's BAA.

Q. How will Clearwater interconnect and deliver energy to PGE's customers?

A. Several steps will occur for Clearwater to interconnect and deliver energy to PGE's customers:

1. First, Clearwater will deliver energy to the Colstrip Substation via a 100-mile generation tie line constructed and owned by Clearwater Resources.
2. From the Colstrip Substation, Clearwater will deliver energy to customers under multiple transmission service agreements with NWE granting Clearwater Resources 300 MW of long-term firm transmission from the Colstrip Substation to the Garrison 230 kV Substation.[29] The firm transmission agreements and rights will be transferred to PGE.
3. From the Garrison Substation, Clearwater will use 180 MW of long-term firm transmission secured by Clearwater Resources from BPA to PGE's load. These firm transmission rights have been transferred to PGE. Additionally, through 2025, Clearwater will use an additional 50 MW of transmission service from the Snohomish County Public Utility District (PUD) that will be redirected to move power from the Garrison Substation to PGE's load.

---

[27] NorthWestern Corporation, Puget Sound Energy, Inc., Avista Corporation, PacifiCorp, and PGE each own a 20% share of the CTS.

[28] A pseudo-tie is a time-varying energy transfer that is updated in real-time allowing the generator of a Balancing Authority Area (BAA) to physically reside outside the contiguous boundaries of the BAA.

[29] PGE's owned portion is for 208 MW and the contracted portion is for 103 MW, resulting in a combined 311 MW. However, Clearwater is limited to 300 MW of total output at the point of interconnection (i.e., Colstrip Substation).

Q. Does Clearwater align with PGE's Interim Transmission Solution and 2021 RFP constraints that required renewable resource bidders to have a plan to secure long-term firm transmission for at least 80% of a project's output?

A. Clearwater has secured 300 MW of long-term firm transmission from the Colstrip Substation to BPA's Garrison Substation. However, the long-term firm transmission secured from the Garrison Substation to PGE's BAA is only 180 MW, which accounts for approximately 60% of Clearwater's output.

When considering the 50 MW of long-term transmission service provided by Snohomish County PUD, Clearwater will have access to a total of 230 MW of long-term firm transmission (approximately 77% of the project's 300 MW output from the Garrison Substation), an arrangement the IE considered acceptable given PGE's renewable and capacity needs.[30]

Q. Please elaborate on transmission scarcity issues and PGE's renewable and capacity needs.

A. Transmission scarcity issues are a primary concern for PGE as we strive to integrate an increasing amount of renewable energy sources (e.g., Clearwater) while also meeting growing electricity demand and HB 2021 emissions reduction goals. Some of the key transmission scarcity issues relate to renewable energy integration, grid congestion and curtailment, transmission capacity expansion, modernization of aging infrastructure, and regulatory and permitting issues.

In response to these challenges and with the enactment of HB 2021, PGE's renewable and capacity needs have evolved significantly. We face the ambitious task of achieving

[30] UM 2166 *Request for Acknowledgment of the Final Shortlist of Bidders in Portland General Electric Company's 2021 All-Source Request for Proposals.* Bates White Final Closing Report, May 5, 2022. page 2.

aggressive emissions reduction targets while dealing with ongoing transmission scarcity. In this environment, it is necessary for PGE to adopt a more flexible approach in considering constraints and requirements in RFP project bids. This adaptation and flexibility to our approach address the changing energy landscape and seek innovative solutions to transmission constraints.

Q. Have other regional partners recognized and begun the process of addressing transmission scarcity issues?

A. Yes. For example, in July of 2023, BPA announced they are moving forward with more than $2 billion in multiple transmission substation and line projects[31] necessary to reinforce the grid. The projects are intended to increase capacity by approximately 6,000 MW, which will accommodate regional growth and the integration of numerous new clean energy resources. If constructed, the projects would facilitate the addition of thousands of megawatts of renewable energy added to the power grid and help Oregon and Washington utilities meet 2030 clean energy targets.

Q. What options are currently available to wheel additional power across BPA's transmission system to PGE's load?

A. Should additional transmission service be required, PGE has several options to wheel power across BPA's transmission system to PGE's load:

- Option 1: PGE can make short-term non-firm purchases on BPA's system.
- Option 2: PGE can utilize PGE's BPA rights associated with the Colstrip generation facility if and when available.

[31] *See* Evolving Grid Project Summaries, evolving-grid-project-summaries.pdf (bpa.gov)

- Option 3: PGE can purchase additional transmission on Avista's transmission system and transport energy to the Mid-C.

These mitigation options for addressing transmission needs remain consistent during and after the 2023-2025 time period, even with the transfer of 50 MW of long-term transmission service by Snohomish County PUD.

B. Owned Wind Resources

Q. Please describe the primary agreements that comprise PGE's 208 MW complete ownership share of Clearwater East.

A. PGE's complete ownership share is governed by three primary agreements: the BTA, the EPC Agreement, and the O&M Agreement. While several additional secondary agreements further define the roles and obligations of the multiple parties, we will focus on discussing the three primary agreements listed above.

Q. Please describe the BTA.

A. The BTA provides for PGE to purchase sole ownership in all 208 MW of the turbines from Clearwater East and supporting infrastructure, including the project collector substation, electrical collection systems, and O&M building, at or near COD. The BTA is a fixed-price contract to reduce the risk to PGE's customers of schedule delays and construction costs. Of note, the BTA includes damages protection against project delays and includes a wake impact agreement, which protects Clearwater East from the wake impacts of neighboring wind farm projects that may be developed by NEER in the future.

Q. Please briefly describe the EPC agreement.

A. The EPC agreement defines the contractor responsibilities and work to be performed with respect to PGE's complete ownership of Clearwater East, including engineering design requirements, equipment and materials requirements, and construction responsibilities. The EPC agreement is between Clearwater Wind East, LLC and will be assigned from Clearwater Wind East, LLC to PGE once Clearwater East achieves commercial operation when the facility transfers to PGE through the BTA.

Q. What is included within the O&M agreement?

A. The O&M agreement is a 20-year[32] time and materials agreement that covers both the day-to-day onsite operations along with the maintenance of Clearwater East, including all capital replacements, except for failure of the main power transformer and failures due to design defects. The agreement is inclusive of all project facilities including the turbines, collector system and substation. The O&M agreement leverages NEER's operational wind expertise, while greatly reducing the overhead involved with hiring and managing plant personnel.

Q. How are PGE and NEER coordinating construction oversight of Clearwater East?

A. Clearwater East and PGE have mutually engaged Sargent and Lundy as the independent engineer. Sargent and Lundy's scope of work is to certify the facility is constructed in accordance with the agreements and agreed upon PGE technical specifications. Sargent and Lundy is also charged with resolving any technical disputes between PGE and Clearwater East.

Q. Is there any warranty with GE for the turbines?

A. Yes. There is an industry standard two-year warranty for the turbines and a warranty on the tower and turbine equipment. Additionally, PGE will purchase additional Serial Defect Protection for the turbines directly from GE.

Q. Are there any other warranties in place?

[32] With two contractually specified renewal options for a total of ten additional years.

A. Yes. In addition to the protections secured within the BTA agreement, there are warranty provisions in the EPC Agreement that ensure the work will be free from defects. The contractor warranty period commences on the Substantial Completion Date and continues for two years. In addition, NEER's EPC contractor is required to maintain insurance coverage including commercial general liability, business automobile liability, and excess or umbrella liability insurance during the construction phase of the project.

Q. What plant performance guarantees has PGE secured?

A. Before the plant is substantially complete, Sargent and Lundy, as the independent engineer, must provide certification that the project meets all contractual, including, achieving the turbine capacity in accordance GE's specifications and passing a 75-hour performance run test to demonstrate that the facility operates satisfactorily and safely. Additionally, GE provides both a power curve and a sound level guarantee for the turbines.

Q. Are there protections against schedule delays?

A. Yes. Clearwater East is required to meet project substantial completion (i.e., commercial operation date or COD) by December 31, 2023 and is subject to liquidated damages for failure to meet this date, which financially compensates PGE for the cost of incremental generation in place of the lost production.

C. Power Purchase Agreement

Q. Please describe the PPA terms between PGE and NEER for Clearwater II.

A. The sale of the output from the entire 103 MW Clearwater II project is governed by a PPA that has a 30-year contract term beginning upon commercial operation of Clearwater II, which is currently projected for December 31, 2023. If Clearwater II is not online by December 31, 2023, Clearwater II will pay escalating delay damages until the earlier of the COD or guaranteed COD, set at 120 days after COD. All prices are non-escalating over the term of the contract and are for specified energy delivered to the Colstrip Substation. The total project output is a bundled product (energy and associated REC), as such, the project output can be used to meet Oregon RPS obligations.

IV. Clearwater Project Costs and Revenue Requirement

Q. Is the project within budget and on schedule?

A. The project is currently within budget and NEER still reflects the expected COD as December 31, 2023. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Q. How did you estimate the operating costs and revenue requirement for Clearwater?

A. We estimated the operating costs and dispatch benefits on an annualized basis, reflecting both costs and benefits for a full year of operations in 2024.

Q. Should Clearwater come online either earlier or later than December 31, 2023, will that impact PGE's revenue requirement?

A. Potentially. Should the project come online significantly earlier or later than December 31, 2023 (i.e., more than a couple weeks in either direction), there would likely be impacts to PGE's forecast of NVPC benefits along with PGE's rate base and depreciation assumptions.

Q. Please explain.

A. While PGE's revenue requirement is an annualized amount assuming a full year of 2024 costs and benefits, because forecast NVPC benefits vary significantly between months, the timing for when each phase of Clearwater (i.e., the PPA and owned portion) actually achieves COD can significantly impact an annualized power cost amount. As it relates to capital and associated costs (e.g., depreciation expense), should the owned portion of Clearwater be early or delayed there could be impacts to PGE's allowance for funds used during construction (AFUDC), the period basis for determining ADIT, and pre-COD test energy benefits.

Q. How does PGE propose to address this?

A. PGE is monitoring the Clearwater schedule, will continue to pursue all rights and remedies under the BTA, and will provide updates to any official changes in project timing and ultimately update the actual COD during the pendency of this proceeding. Accordingly, should any changes materially impact the schedule, PGE proposes to update the annualized NVPC and capital-related components accordingly to align with the project COD.

Q. What are the forecast costs associated with Clearwater?

A. PGE's forecast for Clearwater consists of the following major categories:

- Gross plant in-service totals approximately $432.7 million, including AFUDC and property taxes. Our estimate for the total capital cost (including AFUDC and property taxes) of Clearwater is higher than the total project cost of the RFP bid due to additional costs associated with qualifying for the Energy Community benefit as defined in Internal Revenue Code (I.R.C.) Section 45(b)(11). As we discuss further below, while additional capital costs were incurred, the forecasted benefit accrued to customers associated with increased PTC value is expected to be greater than the incremental costs. Partially offsetting this cost is the inclusion of forecasted pre-COD NVPC benefits (i.e., test energy), which are able to be capitalized prior to a facility's in-service date.
- Production O&M expenses total approximately $3.5 million on an annualized basis. This amount is largely made up of the time and materials O&M contract with NEER, as described in Section III, above, along with utilities costs.

- Insurance and Administrative & General expenses total approximately $0.3 million.
- The first full year of property and other taxes for Clearwater amount to approximately $6.7 million.
- Annualized first-year depreciation expenses total approximately $16.8 million, based on the Commission-approved depreciation study from Docket No. UM 2152, Order No. 21-463.
- Accumulated depreciation and ADIT total approximately ($16.8 million) and $19.2 million respectively.
- NVPC totals approximately ($74.9 million). This reflects PPA costs, ancillary service and integration costs, transmission (i.e., wheeling) costs, land-owner royalties and land lease payments, which are variable based on generation, and other miscellaneous variable charges, net of forecast PTCs, energy benefits, and diversity benefits. Detailed supporting documentation, consistent with PGE's minimum filing requirements included with PGE's annual update tariff (AUT), are provided in our work papers.

Q. Please provide additional detail regarding the costs and benefits associated with qualifying for the Energy Community benefit.

A. During contract negotiations, PGE was informed that Clearwater could likely qualify for the Energy Community bonus, as newly defined in I.R.C. § 45(b)(11).[33] While the ability to qualify required additional work and costs, it became clear that the incremental benefit of a 10% increase to the PTC value greatly outweighed the incremental cost of approximately $5.8 million.[34] Thus, while this additional cost was not originally scoped within the RFP bid, PGE

[33] This was subsequently confirmed based on NEER's PTC Qualifying Tax Opinion.
[34] For reference, the current 2024 NVPC benefit associated with the Energy Community bonus as forecast and included within this filing totals approximately $3.2 million.

determined pursuing this benefit is beneficial to customers as it is forecast to result in a net reduction to customer prices over the life of the project. Upon the closing date of the project, PGE will receive a PTC Qualification Certificate, and payment for the incremental capital will only be made to the extent the PTC Qualification Certificate supports the project's eligibility for the bonus.

Q. Does Clearwater qualify for any other incremental PTC benefits?

A. Possibly. PGE was recently notified by NEER that Clearwater may qualify for the Domestic Content bonus as defined within I.R.C. § 45(b)(9). Similar to the Energy Community benefit, the Domestic Content bonus provides an incremental 10% PTC benefit. PGE is currently investigating both the likelihood and potential costs and benefits associated with qualifying for this incremental benefit at this late stage of the project.

Q. Please briefly describe how NVPC is forecast for Clearwater.

A. NVPC is forecast within PGE's MONET model, assuming that both the PPA and owned portions of Clearwater are in service for the entirety of 2024. The costs included are consistent with Clearwater's contract and consistent with MONET modeling used for PGE's 2024 NVPC forecast in UE 416, with the addition of two key items. Specifically, PGE has incorporated modeling of wind diversity benefits and a modeled forecast of transmission constraints.

Q. Please describe the diversity benefit modeling.

A. PGE has incorporated a forecasted diversity benefit to reflect the geographical diversity of Clearwater in Montana compared to PGE's other wind facilities located within the Columbia

River Gorge (Gorge). As such, MONET's forecast recognizes that the generation production profile for Clearwater differs from that of the Gorge facilities.

Q. How is this benefit modeled?

A. As there is no actual generation data for Clearwater, PGE utilized generation estimates calculated from actual hourly meteorological tower data at the Clearwater site from November 2014 through 2021. The generation forecast was produced by DNV Energy, considering many factors particular to the Clearwater project and the available meteorological tower data. They created a time series for a typical meteorological year which best represents the median production over the long term. Using this data, PGE included Clearwater's expected hourly generation profile with PGE's existing fleet of wind over the same time horizon (along with solar and load) to calculate an updated hour ahead forecast error (HAFE) regression model. This model was used to calculate PGE's new ancillary services (AS) requirement, which reflects the lower need per MW of nameplate to integrate PGE's wind facilities. This lower AS need (per MW nameplate) is driven by the differences between the generation shape of Clearwater compared to PGE's existing Gorge wind fleet. The difference in shape causes forecast errors to sometimes mitigate each other (e.g., Gorge wind was higher than the hour ahead forecast while Montana wind was lower than the hour ahead forecast), which reduces how much capacity PGE needs to reserve for HAFE relative to the size of the fleet. The benefit is calculated by comparing the NVPC cost of integrating Clearwater if we update the HAFE model to the NVPC cost if we treated it as if it were another Gorge wind plant.

Q. What portion of NVPC benefits are associated with the diversity benefit modeling?

A. The forecast benefit in MONET from Clearwater's locational diversity is approximately $11.8 million.

Q. How does PGE model Clearwater transmission needs?

A. Similar to other transmission products in MONET, all transmission contracts are modeled based on their fixed monthly contract costs over the year. Additionally, because Clearwater does not have rights to 100% firm transmission for delivery and has a contractual obligation to pay a compensable curtailment charge to NEER for its PPA portion,[35] PGE includes assumptions for both potential curtailment and the purchase of short-term transmission.

Q. How does MONET model these assumptions?

A. MONET uses historical short-term transmission availability to determine the number of hours that short-term transmission is likely to be unavailable and generates a probability percentage. Using this probability of availability, PGE generated 1,000 random scenarios to simulate the range of possible cost to PGE depending on when the hours of unavailability will occur throughout the year. The 50th percentile of these scenarios, in terms of cost, is used to generate the reference scenario for input into MONET. To determine the impact each hour, the following method is used:

1. If hourly generation is under the long-term firm rights of 230 MW, no action is required.
2. If hourly generation exceeds 230 MW, short-term transmission is purchased for the amount in excess, if available.
3. If short-term transmission is unavailable, one-third of the curtailed amount (i.e., the PPA portion) is counted towards PGE's curtailment allowance.

[35] Which is triggered if the cumulative PPA curtailment exceeds **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** within a year.

4. If the curtailed amount for the year exceeds the PPA curtailment allowance, a curtailment charge is applied.
5. Curtailed energy for both the PPA and Owned portions is removed from Clearwater's generation shape before input into MONET.

Q. Is Clearwater currently modeled to exceed the PPA curtailment allowance?

A. No. The current expectation is that Clearwater will not exceed the PPA curtailment allowance.

Q. What is the forecasted cost of additional short-term transmission?

A. PGE's current forecast of short-term transmission costs, using the above methodology, is approximately $0.3 million. This is priced at the BPA Hourly Point-to-Point rate.

Q. How does PGE expect to model curtailment and short-term transmission in the future?

A. Once Clearwater is operational and PGE has access to historical data, we will incorporate historical short-term transmission purchases and compensable curtailment charges into our modeling of these costs.

Q. What is the revenue requirement impact of Clearwater?

A. Including the current forecast of NVPC, the 2024 revenue requirement for Clearwater is approximately ($9.9 million).

Q. When is PGE requesting prices to recover Clearwater costs to be effective?

A. As stated in Section I above, we are requesting a price effective date of June 1, 2024. PGE is also filing a request for deferred accounting, concurrent with this testimony. PGE's application for deferred accounting is intended to capture the revenue requirement associated with the period between Clearwater's online date and the tariff-effective date of Schedule 122. Additionally, any associated expense amounts incurred prior to Clearwater's online date that are the direct result of bringing Clearwater into service but cannot be capitalized may be included within PGE's application for deferred accounting. Any deferred costs will then be included in a future Schedule 122 update.

V. PTC and REC Proposals

Q. Please describe the IRP assumptions made regarding PGE's near-term REC needs.

A. At the time PGE performed analysis for the 2019 IRP, we did not identify near-term needs for additional RECs to meet Renewable Portfolio Standard (RPS) obligations.[36]

Q. How did this assumption impact PGE's Renewable Action Plan?

A. As part of the IRP Action Plan, acknowledged through Commission Order Nos. 20-152 and 21-129, PGE proposed to treat generated RECs prior to 2030, consistent with the proposal in PGE's 2016 IRP Revised Renewable Action Plan (Docket No. LC 66).[37] Specifically, PGE identified the following options within the 2016 IRP: 1) sell RECs bilaterally or through an RFP, 2) sell RECs to retail subscribers of renewable portfolio options programs, or 3) evaluate the future alternative policy compliance value of RECs.

Q. Does PGE have a proposal regarding RECs produced from Clearwater prior to 2030 in this proceeding?

A. No. Since 2021, various factors including changes to PGE's load forecast, REC bank, the market for unbundled RECs, and shifts in Washington State's policies[38] have prompted PGE to conclude that the most reasonable course of action may be to retain the RECs generated from Clearwater. However, PGE is still exploring the need to retain these RECs versus the options described as part of PGE's 2016 and 2019 IRPs.

---

[36] PGE's 2019 IRP, page 26.
[37] PGE's 2019 IRP, page 34.
[38] In 2021 the Washington Legislature passed the Climate Commitment Act (CCA) which established a cap-and-invest program.

Q. Please discuss PGE's current and near-term expected REC needs.

A. Based on data and calculations relied upon for PGE's September 6, 2023 IRP reply comments, without assuming the use of Clearwater RECs, a shortage of RECs is assumed beginning in 2034. Importantly though, this projection assumes that 20% of PGE's annual compliance will be met using zero cost unbundled RECs and it assumes a PGE REC bank inventory that is no longer current. If updating to a more current REC bank inventory, PGE's projected shortage moves to 2031 under a high load scenario. Additionally, if also removing the 20% unbundled REC assumption, PGE's projected shortage begins in 2026 under the high load scenario and 2027 under the reference scenario.

Q. Why are you looking at PGE's RPS needs without the assumption of unbundled RECs?

A. While using up to 20% unbundled RECs is permitted by ORS 469A.145(1) and a strategy that PGE currently employs and anticipates employing when practicable, it may not remain the most cost-effective option for the entire 20% allowance. This is because, while the IRP does not assign a cost to procuring unbundled RECs, it is not a cost-free option for PGE. In fact, as voluntary renewable programs continue to grow nationally, the demand for unbundled RECs continues to grow, which has had a direct impact on the price of these RECs. According to the National Renewable Energy Laboratory, unbundled RECs remain the most common source of green power supply, with the market growing 23% from 2020 to 2021 and the price of a nationally sourced REC increasing from $1.50/MWh to $6.60/MWh over the same time period.[39]

[39] Status and Trends in the U.S. Voluntary Green Power Market (2021 Data) (nrel.gov), page 7, at https://www nrel.gov/docs/fy23osti/86162.pdf

Q. Please briefly describe the Washington CCA and how it impacts PGE.

A. In 2021, the state of Washington passed the Climate Commitment Act,[40] which established a comprehensive, market-based cap-and-invest program.[41] The Washington Department of Ecology finalized the cap-and-invest program regulations in October 2022 and the program was launched on January 1, 2023. Thus, entities that are covered under the program started incurring emission compliance obligations on January 1, 2023. Given PGE's current and historical level of energy imports into the state of Washington, PGE is a covered entity under the program and is required to comply with the program requirements.

Q. How does this impact Clearwater RECs?

A. One option for avoiding a carbon obligation is importing specified non-emitting energy such as the energy produced from Clearwater. While this type of transaction is difficult to execute on a forward basis due to the intermittency of wind, it is certainly possible that PGE will be able to deliver specified energy from Clearwater into the state of Washington to reduce our compliance costs. However, for Clearwater or other renewable energy to avoid a carbon obligation, the REC cannot be used for another purpose. Thus, for this to be a beneficial market product for PGE, we must retain the flexibility to sell the associated REC.

Q. Would this type of transaction benefit customers?

A. Yes. As part of the Third Partial Stipulation filed in Docket No. UE 416 and pending before the Commission, PGE and other stipulating parties agreed that PGE will submit a deferral application covering all 2024 carbon compliance costs associated with the Washington CCA. As such, should PGE avoid Washington carbon obligations through the import of specified

---

[40] Available at: https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act
[41] Available at: https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act/Cap-and-invest

carbon-free resources such as Clearwater, 2024 carbon compliance costs will be reduced for customers.

Q. How does PGE propose to treat PTCs associated with Clearwater?

A. We propose as part of this proceeding that PGE remove the Clearwater-associated deferred tax asset (DTA) from our forecast ADIT balance and seek to sell generated PTCs through a property sales application. PGE's proposed sale structure in this proceeding would mirror the agreement within the UE 416 Second Partial Stipulation, which is currently pending Commission approval.

Q. Please describe the pending stipulated agreement in UE 416 associated with PTCs.

A. Customers continue to receive the full benefit of the PTCs as forecast within PGE's net variable power costs, while a property sale application will seek to recover the difference between the full value and the discounted sales value from customers within PGE's property sales balancing account, so long as the difference is no greater than 10%. If PGE cannot secure a transaction that would maintain 90% or more of the PTC value, PGE will not proceed with the transaction and the PTCs will return to the DTA in PGE's test year rate base for this proceeding.

VI. Clearwater Timeline and Milestones

Q. Does the agreement with NEER contain a substantial completion deadline for PGE's owned and contracted portions of Clearwater?

A. Yes. The substantial completion deadline for Clearwater East and Clearwater II is December 31, 2023. NEER will be liable for liquidated damages if the work is not completed by the substantial completion date.

Q. How far along is construction at the time of this filing?

A. Construction at Clearwater East and Clearwater II commenced in May 2023. The planning and execution of Clearwater East and Clearwater II is proceeding on schedule.

Q. What are the project milestones associated with Clearwater East and Clearwater II?

A. Tables 3 and 4 below lists the estimated construction and testing milestones.

Table 3
Clearwater East Milestones

Milestone	Actual/Scheduled Completion
Start of Construction	May 2023 (Achieved)
Test Energy	November 2023
Wind Turbine Mechanical Completion	November 2023
Final Wind Farm Commissioning	December 2023
Commercial Operation	December 2023

Table 4
Clearwater II Milestones

Milestone	Actual/Scheduled Completion
Effective Date	October 2022
Seller Approval Date	December 2022
Test Energy	November 2023
Commercial Operation	December 2023

VII. Qualifications

Q. Mr. Abel, please describe your qualifications.

A. I received my Bachelor of Science degree in Civil Engineering from the University at Buffalo in New York. I have been employed at PGE since July 2021, working in the construction project management group and before that, I have held various positions with developers and contractors working primarily in the renewable energy field.

Q. Mr. Batzler, please describe your qualifications.

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	2024 Clearwater Revenue Requirement
102C	IE Letter to Commissioners

Portland General Electric Company
2024 Clearwater Revenue Requirement
Dollars in $000s

		RevReq
1	Sales to Consumers	(9,898)
2	Sales for Resale	
3	Other Revenues	
4	Total Operating Revenues	(9,898)
5	Net Variable Power Costs	(74,893)
6	Production O&M (excludes Trojan)	3,500
7	Trojan O&M	
8	Transmission O&M	
9	Distribution O&M	
10	Customer & MBC O&M	
11	Uncollectibles Expense	(40)
12	OPUC Fees	(47)
13	A&G, Ins/Bene., & Gen. Plant	289
14	Total Operating & Maintenance	(71,191)
15	Depreciation	16,845
16	Amortization	
17	Property Tax	6,462
18	Payroll Tax	
19	Other Taxes	271
20	Franchise Fees	(254)
21	Utility Income Tax	7,665
22	Total Operating Expenses & Taxes	(40,203)
23	**Utility Operating Income**	30,305
24	**Rate Base**	
25	Gross Plant	432,662
26	Accum. Deprec. / Amort	(16,845)
27	Accum. Def Tax	19,269
28	Accum. Def ITC	
29	**Net Utility Plant**	435,086
30	Misc. Deferred Debits	
31	Operating Materials & Fuel	

32	Misc. Deferred Credits	
33	Working Cash	(1,697)
34	**Rate Base**	433,389
35	**Rate of Return**	6.993%
36	**Implied Return on Equity**	9.500%
37	Effective Cost of Debt	4.485%
38	Effective Cost of Preferred	0.000%
39	Debt Share of Cap Structure	50.000%
40	Preferred Share of Cap Structure	0.000%
41	Weighted Cost of Debt	2.243%
42	Weighted Cost of Preferred	0.000%
43	Equity Share of Cap Structure	50.000%
44	State Tax Rate	7.562%
45	Federal Tax Rate	21.000%
46	Composite Tax Rate	26.974%
47	Bad Debt Rate	0.400%
48	Franchise Fee Rate	2.565%
49	Working Cash Factor	4.222%
50	Gross-Up Factor	1.369
51	ROE Target	9.500%
52	Grossed-Up COC	8.747%
53	OPUC Fee Rate	0.473%
	Utility Income Taxes	
54	Book Revenues	(9,898)
55	Book Expenses	(47,868)
56	Interest Deduction	9,719
57	Production Deduction	
58	Permanent/Flow Through Ms	(166)
59	Deferred Ms	(1,505)
60	Taxable Income	29,922
61	Current State Tax	2,263
62	State Tax Credits	
63	Net State Taxes	2,263
64	Federal Taxable Income	27,660
65	Current Federal Tax	5,809
66	Federal Tax Credits	
67	ITC Amort	
68	Deferred Taxes	(406)
69	Total Income Tax Expense	7,665
70	Regulated Net Income	20,586
71	Check Regulated NI	20,586